Commonwealth of Kentucky
Division for Air Quality

PERMIT STATEMENT OF BASIS

TITLE V PERMIT NO: V-02-043 REVISION 1
Louisville Gas and Electric Company
P.O. Box 32010, Louisville, Kentucky 40232
JANUARY 20, 2005
BEN MARKIN, REVIEWER
SOURCE I.D. #: 021-223-00002
SOURCE A.I. #: 4054
ACTIVITY #: APE 20040004

CHANGES TO PERMIT (REVISION 1):-*MINOR MODIFICATION*:

Louisville Gas & Electric Company submitted to the Division two minor revision applications on November 29, 2004 and December 21, 2004. The initial application was for a voluntary creditable decrease in emissions for the permitted emission unit 01, a 5333 mmBtu/hr, pulverized coal fired boiler installed in 1990. The creditable decrease in emissions will be 1485 tons per year of nitrogen oxide. This permit will limit the twelve (12) month rolling total for nitrogen oxides (NO_x) on the unit to 5556 tons per year. The credible reduction is requested by the facility to net against future potential increase from the construction of an additional utility boiler. The practically enforceable creditable reduction is being done in accordance with the recently revised new source review (NSR) rules. [401 KAR 51:001 and 51:017] Compliance with the emissions limit shall be demonstrated using continuous emission monitoring equipment and procedures required by 401 KAR 52:060 (acid rain program). The annual limit for NO_x will be based on 0.45 lb/mmBtu established from the acid rain program for the existing boiler, instead of the permitted BACT allowable limit of 0.7 lb/mmBtu, with the installed selective catalytic reduction (SCR) unit.

Emission Unit 01-Emission Limitations:

Pursuant to 401 KAR 51:001, Section 1, (146), source has accepted a voluntary limit such that consecutive twelve month rolling total of nitrogen oxide emissions shall not exceed 5556 tons per year, which through this permit is enforceable as a practical matter.

Compliance with nitrogen oxide emissions:

Permittee shall monitor and calculate emissions on a consecutive twelve month rolling total as measured by the continuous emissions monitor (CEM) required pursuant to 40 CFR 75.

The second application is for the proposed usage of two or three dry bulk trailers with tractors to transport the fly ash from the existing fly ash silo emission point 19 (2E and 2F) at the facility. The vehicle miles traveled (VMT) area assumed to neither decrease nor increase in the disposal process. The proposed trailers are capable of unloading into a barge in forty to sixty minutes; while offloading can be occur at a rate of twenty five to thirty five minutes. The fly ash will be discharged from the trailer through a cyclonic material handler, and flow by gravity into the barge. The airflow from the material handler will pass through a baghouse. With an hourly throughput rate of 35 ton trailer loads from the trans loading operations, the allowable PM emission rate is 34.16 lb/hr however, the potential to emit from the process with the collector will be 0.17 lb/hr, and 0.10 lb/hr from the drop loading controlled by an extendable chute for particulate matter (PM/PM10). In order to meet the prevention of significant deterioration (PSD) requirements, the permittee requests that the allowable rate for combined process should be limited to 0.027 lb/hr and 1.20 tons per year of PM/PM10 for the trailers transporting the fly ash. 401 KAR 59:010 is applicable to the proposed units however, the total particulate emissions from the units is below the five tons per, therefore the units will be considered as insignificant, and will be added to the list in the permit.

PAST PERMITING ACTIONS

Louisville Gas & Electric Company is an existing source with coal fired and natural gas fired peaking units for electricity generation in Trimble County, Kentucky. The source has a draft Title V permit issued in 1997, which has undergone public/U.S.EPA review (12-18-1997) however, the final permit was not issued. An acid rain permit, which underwent public review (12-24-98), was issued for the boiler with NO_x averaging and SO_2 allowances in 1996 (AR-96-007), and revised NO_x averaging and SO_2 allowances permit issued on March 5, 1999 (A-98-011). In addition, the source submitted a permit application to construct and operate natural gas fired peaking units, which were granted a PSD permit on June 22, 2001, after public/U.S.EPA review (5-17-2001). A Phase II acid rain application for the combustion turbines (CTs) received on June 12, 2001 has not been drafted or issued. Other than the new acid rain application for the combustion turbines, all three permit applications were called administratively complete on 12-12-1996 (draft TV permit), 12-24-1998 (first Title IV permit), and 01-14-01 (PSD permit) respectively.

The Division has decided to issue a source-wide proposed permit to incorporate the draft TV, PSD, existing acid rain permit for unit 1 and a Phase II draft permit for the CTs. The reason being that new CT units have no SO_2 allowances, which are yet to be purchased on the market. The acid rain section will be divided into two; the permitted unit one (1), with allowances and NO_x limits will be the initial part while the second part addresses the CT's (units 25-30) with a draft watermark to indicate that this portion has not been reviewed by the public. The significant change for the entire permit is to give it a new permit number, which will affect the issuance date for the permitted acid rain for unit 1. Given the history above, the proposed permit with the numberV-02-043, will consolidate the authority of any previously issued preconstruction permit terms and conditions for various emission units and incorporates all requirements of those existing permits into one single permit for this source. For continuity, the most current log number and the completeness dates will be used as general numbers for this permit.

SOB FOR TV DRAFT WHICH WENT THROUGH PUBLIC/EPA REVIEW AND WAS READY FOR ISSUANCE, BUT NEVER GOT ISSUED - DRAFT PERMIT # V-97-024 LOG # E720

SOURCE DESCRIPTION, CONTROL EQUIPMENTS & CONSTRUCTION DATE:

E. Unit 01: Unit 1: Pulverized coal-fired, dry bottom, tangentially-fired unit equipped with a Selective Catalytic Reduction (SCR), electrostatic precipitator and wet spray scrubber with lime/limestone injection, construction commenced prior to September 18, 1978.

E. Units 02: Unit 2: Auxiliary boilers A, B, and C, number two fuel oil-fired units, construction commenced prior to December 28, 1987.

E. Unit 05: Unit 5: Continuous barge unloader, one barge unloader bin, fossil fuel stacker reclaimer, one active pile, one inactive pile, stackout, and one reclaim hopper; Plant roadways; construction commenced prior to 1990.

E. Unit 07: Unit 7: Coal/fossil fuel crushing and conveying operations includes conveyors E, R1, F-1, F-2 and transfer points, two primary crushers, fossil fuel crusher bin equipped with enclosure, surfactant use, and rotoclone, construction commenced by 1990;

Coal/fossil fuel processing, conveying and transfer, includes conveyors A, B, C, D, G1, G2, 1, and 2, and transfer points, and fuel blender equipped with partial enclosures, construction commenced by 1990;

Coal/Fossil fuel silos including six fossil fuel silos for Unit 1 equipped with a baghouse, construction commenced by 1990.

E. Unit 10: Units 10: Lime/limestone handling and processing includes clamshell unloader, clamshell barge unloader bin, stockpile/stackout operations, and active and inactive piles equipped with enclosure and wet spray low water surfactant system; construction commenced by 1990.

E. Unit 12: Unit 12: Lime/limestone handling and processing includes underground crushing operation (one crusher), construction commenced by 1990;

Lime/limestone handling and processing, milling operations (two ball mills) equipped with enclosure, construction commenced by 1990.

E. Unit 14: Unit 14: Lime/limestone handling and processing, conveyors and transfer points (conveyor system, belts A, B, C, transfer bin, and reclaim hopper) equipped with partial enclosures, construction commenced by 1990.

E. Unit 18: Unit 18: Emergency diesel generator with maximum horsepower 150 kW, construction commenced by 1995.

E. Unit 20: Unit 20: Cooling tower with five chemical injection pumps and two circulating water pumps, construction commenced by 1990.

E. Units 25-30:

Units 25-30: Combustion Turbines

REGULATION APPLICABILITY:

All the applicable regulations to the emission units are listed in the permit. The following regulations are not applicable based on the applicability date of regulation, unit size, and/or definition of an affected facility per the regulation:

<u>Regulations not applicable to Unit 1 due to applicability date or size of unit:</u>

Regulation 401 KAR 59:016, New electric utility steam generating units, incorporating by reference 40 CFR 60, Subpart Da

Regulation 401 KAR 60:042, Standards of performance for industrial-commercial-institutional steam generating units, incorporating by reference 40 CFR 60, Subpart Db

Regulation 401 KAR 60:043, Standards of performance for small industrial-commercial-institutional steam generating units, incorporating by reference 40 CFR 60, Subpart Dc

<u>Regulation not applicable to Unit 2, (Auxiliary boilers A, B, and C) due to applicability date:</u>
Regulation 401 KAR 60:043, Standards of performance for small industrial-commercial-institutional steam generating units, incorporating by reference 40 CFR 60, Subpart Dc

<u>Regulation not applicable to Unit 5 (Coal/fossil fuel receiving operations, and Coal/fossil fuel stockpile operations, and plant roadways) due to definition of affected facility:</u>

Subpart Y does not apply because barge unloader system does not meet definition of affected facility under Subpart Y. Open stockpile operations do not meet the definition of an affected facility under

Subpart Y. Regulation 401 KAR 60:250, Standards of performance for coal preparation plants, adopting by reference 40 CFR 60, Subpart Y. (Barge unloader, unloader bins, and stacker reclaimer are not thermal dryers, or pneumatic cleaning equipment's, or coal processing and conveying equipment by definition; these do not convey coal or remove coal from machinery to reduce the size of coal nor do these separate coal from refuse; the stockpiles are open which does not meet definition of coal storage system under Subpart Y, and stackout conveyor S and two inactive reclaim hoppers do not meet the definition of an affected facility)

<u>Regulation not applicable to Unit 10 (Lime/limestone handling and processing) due to definition of an affected facility:</u>
Receiving units and operations and stockpile/stackout operations do not meet the definition of an affected facility under Subpart OOO which therefore does not apply.
Regulation 401 KAR 59:310, New nonmetallic mineral processing plants (40 CFR 60, Subpart OOO as modified by Section 2 of Regulation 401 KAR 59:310) because the clamshell unloader and bin, and stockpile operations do not meet the definition of an affected facility - do not include crushers, grinding mills, screening, bucket elevators, belt conveyors, bagging operations, storage bin, or loading station.

REGULATION APPLICABILITY:

<u>Regulations not applicable to Unit 18, Emergency diesel generator:</u>
Subparts D, Da, Db, or Dc do not apply because the diesel generator is an engine not an indirect heat exchanger.

COMMENTS:

- The permittee must comply with the Acid Rain Permit, Number AR-96-07 issued December 19, 1996.
- The permittee has not proposed any alternate operating scenario for the emissions units.
- Unit 1 boiler has Continuous Emission Monitors for sulfur dioxide, nitrogen oxides, and opacity which may be used to assure compliance.
- The permittee will be required, for Unit 1, to conduct one performance test for particulate emissions in the first six months after permit issuance to demonstrate compliance with the allowable standard and to develop the indicator range/upper limit for opacity. The permittee may assure continuing compliance with the particulate standard using continuous opacity monitoring data as an indicator as described in the permit. If no other performance tests for particulates are performed, then a second performance test for Unit 1 will be required in the third year of the permit term.
- See the Permit Application Summary Form for important points to note regarding the three 11.76 MMBTU/hour auxiliary boilers.
- Unit 5, Unit 10, and Unit 20 subject to fugitive emissions Regulation 401 KAR 63:010 and are considered to be in compliance when using control measures required by the regulation.
- Unit 7, Unit 12, Unit 14 have a periodic monitoring requirement to conduct weekly inspections of control equipment making necessary repairs to assure proper maintenance and/or operation of control equipment, and annual Method 9 opacity readings or Method 22 testing as appropriate to assure compliance.
- Unit 18 emergency diesel generator is not subject to any applicable requirements, and is an engine, not an indirect heat exchanger.
- The permittee shall submit a compliance assurance monitoring (CAM) plan for applicable emissions units with an application for significant revision or with the application for the

Title V permit renewal.

PSD SOB FOR COMBUSTION TURBINES PERMITTED ON JUNE 22, 2001- PERMIT # V-01-012, LOG #53460

EXECUTIVE SUMMARY

Louisville Gas & Electric submitted a permit application to construct and operate a natural gas fired peaking station for electricity generation in Trimble County, Kentucky. The Trimble County Generating Station already consists of one coal-fired unit of approximately 525 MW. This project will add six (6) General Electric PG7241 (FA) natural gas-fired combustion turbines which will operate in simple cycle mode with a nominal output capacity of 160 megawatts (MW) each. Each turbine will be equipped with its own exhaust stack. This proposed modification to the existing facility is to increase peak power supply. The modification is to produce electricity during periods of peak electricity demand on a daily and seasonal basis. The plant will not be restricted in its hours of operation. The proposed modification will be a major modification at an existing major source as defined in Kentucky State Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of Significant Deterioration (PSD) of air quality. Emissions of the following regulated pollutants are in excess of the referenced significant emission rates: 40 tons per year of nitrogen oxides (NOx); 100 tons per year of carbon monoxide (CO); 15 tons per year of particulate matter less than 10 microns (PM_{10}); 40 tons per year of sulfur dioxide (SO_2); 40 tons per year of Volatile Organic Compounds (VOC). Emissions of beryllium, cadmium, chromium, copper, formaldehyde, lead, manganese, nickel, sulfuric acid and mercury are subject to Regulation 401 KAR Regulation 401 KAR 63:020, Potentially hazardous matter or toxic substances.

The plant already belongs to one of the 28 major source categories listed in 401 KAR 50:017 because of the existing coal-fired utility boiler. The source will be located in a county classified as "attainment" or "unclassified" for NO_2, CO, SO_2, PM_{10} and ozone pursuant to Regulation 401 KAR 51:010, Attainment status designations. Consequently, the proposed facility meets the definition of a major modification at a major stationary source and is subject to evaluation and review under the provisions of the PSD regulation for all these pollutants. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

Since this review demonstrates that all applicable PSD, NSPS, NSR, and air toxic requirements will be met, a preliminary determination has been made that the construction permit should be issued as conditioned, but contingent on the satisfactory resolution of any adverse public comments which might be received.

BACKGROUND

A construction permit application was received from Louisville Gas & Electric on November 16, 2001, and was considered complete by the Kentucky Division for Air Quality on January 14, 2001. The application is for the construction and operation of six (6) natural gas fired, General Electric PG7241 (FA) simple cycle combustion turbines at the existing Louisville Gas & Electric site. Simple cycle turbines differ from a combined cycle in that they do not recover heat from the gas turbine exhaust to preheat the inlet combustion air to the gas turbine, or heat water, or generate steam. Each of these units will have a maximum rated capacity of 160 megawatts. The emission rates from using natural gas fuel (based on 8760 hours per year) were evaluated and compared to obtain a worst-case scenario for the PSD review. All the information used in the determination of this review was derived from the application and assumptions listed therein.

This project is considered a major stationary source since the emissions of particulate matter (PM_{10}), nitrogen oxides (NO_x), and carbon monoxide (CO) each exceed 250 tons/year. Also, there will be a significant emission increase in the emissions of sulfur dioxide (SO_2), beryllium (Be), and volatile organic compounds (VOC). Therefore, the proposed construction is subject to a Prevention of Significant Deterioration (PSD) review for each of these pollutants. In addition, the turbines are subject to the New Source Performance Standards (NSPS) for NO_X and SO_2 since the heat input is greater than 10.0 mmBTU/hour. Emissions of beryllium, cadmium, chromium, copper, formaldehyde, lead, manganese, nickel, sulfuric acid and mercury are subject to Regulation 401 KAR 63:020, Potentially hazardous matter or toxic substances.

For each pollutant subject to the PSD Regulation 401 KAR 51:017, a review of the following is required:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

EMISSIONS ANALYSIS

The proposed Trimble County Generating Station will produce electricity during periods of peak demand. The electricity generation operations will consist of: six (6) new natural gas-fired simple cycle combustion turbines (nominally 160 MW each) equipped with dry low NOx burners. For a detailed description of the plant processes and expected emissions at each emissions point and emissions unit, please see the application. Emissions were based on the maximum rated capacity of the plant, worst case operating conditions, and 8760 hours per year of operating time for each turbine, after controls. The calculated potential emissions from the proposed project are summarized in Table 1 and are calculated for ambient temperature of 57 degrees Fahrenheit and baseload conditions (rated capacity output) utilizing natural gas projecting worst case operating conditions.

TABLE 1 - SUMMARY OF EMISSIONS

Pollutant	Proposed	PSD

	Potential Emissions (Tons/yr)	Significant Emission Rates (Tons/yr)
Particulate (PM_{10})	499.3	25 (15)
Sulfur Dioxide	105.1	40
Carbon Monoxide	762	100
Nitrogen Oxide	1,524	40
VOC	73.6	40
Sulfuric Acid Mist	0.0	7.0
Beryllium	0.013	0.0004
Lead	0.5861	0.6
Mercury	0.0502	0.1

The potential emissions of PM/PM_{10}, NO_x, CO and VOC were obtained from the application and are based on design data from the manufacturer.

In April, 2000, the U.S. EPA revised Chapter 3.1 of AP-42, "Stationary Internal Combustion Sources: Stationary Gas Turbines." In some cases, the emission factors relevant to this application were revised. These revised factors are utilized in this Preliminary Determination. The following calculations represent the worst-case scenario:

CALCULATIONS OF POTENTIAL EMISSIONS:

	Number of Units	**Lb/Hr/Turbine**	**Hours/Year**	**Lb/Ton**	**Lb/Hr Emission Factor Source**	**Tons/Year**
PM10	6	19	8760	0.0005	Manufacture	499.32
CO	6	29	8760	0.0005	Manufacture	762.12
NOx	6	58	8760	0.0005	Manufacture	1524.24
VOC	6	2.8	8760	0.0005	Manufacture	73.584
SO2	6	4	8760	0.0005	Manufacture	105.12
H2SO4	6	0	8760	0.0005	Manufacture	0
Arsenic	6	0.017523	8760	0.0005	AP-42 4/2000	0.4605
Beryllium	6	0.000494	8760	0.0005	AP-42 4/2000	0.0130
Cadmium	6	0.007646	8760	0.0005	AP-42 4/2000	0.2009
Lead	6	0.022302	8760	0.0005	AP-42 4/2000	0.5861
Manganese	6	1.25847	8760	0.0005	AP-42 4/2000	33.0726
Mercury	6	0.001912	8760	0.0005	AP-42 4/2000	0.0502
Nickel	6	0.007328	8760	0.0005	AP-42 4/2000	0.1926
Formaldehyde	6	0.02390	8760	0.0005	AP-42 4/2000	0.628

REGULATORY REVIEW

This section presents a discussion of the air quality regulations applicable to this project. In some cases the emission limit or technology standard based on these regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review); however, any specific testing, monitoring, record keeping, and reporting requirements contained in these regulations will still have to be met by the source in addition to any requirements under PSD.

The following regulations will apply to the proposed modification (please see the application for a detailed description of the plant and specific processes/units within the plant):

Regulation 401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, for emissions units with a heat input at peak load equal to or greater than 10 MMBTU/hour for which construction commences after October 3, 1977, applies to each of the simple cycle gas-fired turbines. The proposed BACT is much less than the applicable standard for nitrogen oxides emissions in Subpart GG, with an hourly limit of 12 ppm by volume corrected to 15 percent oxygen on a dry basis and an annual limit of 9 ppm by volume corrected to 15 percent oxygen on a dry basis. Subpart GG standard for sulfur dioxide is that no owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight. Proposed BACT for sulfur dioxide is consistent with the EPA RACT/BACT/LAER Clearinghouse for gas turbines which fire natural gas containing less than 2.0 grains/100 SCF of sulfur.

Since the combustion turbines are equipped with dry low-NOx burners, sections of Subpart GG related to monitoring water injection rates are not applicable. In accordance with 40 CFR 60.334 to meet the requirement for fuel sulfur content testing, the following alternative fuel-monitoring schedule has been approved;

The Permittee will sample the natural gas for sulfur content every six months; except that when firing pipeline quality natural gas the sulfur content is assumed to be in compliance and testing is not required.

A performance test is required by Subpart GG for nitrogen oxides, oxygen concentrations, and sulfur content. Please refer to 40 CFR 60.335 for further testing details. Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. This source is required to apply for a Phase II Acid Rain permit. Part 75 may require continuous emission monitoring depending on the number of hours the combustion turbines are actually operated.

Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of significant deterioration of air quality, applies to the proposed plant which will be located in Trimble County (currently designated as "attainment" or "unclassified" for all ambient quality standards).

Total potential emissions of all criteria pollutants for the six combustion turbines are:

Pollutant	**PTE * (tons per year)**	**Significant Emission Rate ** (tons per year)**

Nitrogen oxides (NO_x)	1,524	40
Carbon monoxide (CO)	762	100
Sulfur dioxide (SO_2)	105	40
Particulate (PM)	499	25
Particulate matter (PM_{10})	499	15
Volatile organic compounds (VOC)	74	40

* PTE - Potential to emit, emissions for turbines calculated with 8760 hours/year operation and worst case operating conditions, and include ancillary equipment.

** Significant emission rate as given in Regulation 401 KAR 51:017, Section 22.

As seen in the table above, the modification will be a major modification for nitrogen oxides, carbon monoxide, sulfur dioxide, and VOCs. The PSD review applies to every pollutant that the proposed plant will emit in significant quantities, i.e., in amounts that will exceed the respective significant net emission rate. As seen above, the plant will be subject to PSD review for nitrogen oxides, carbon monoxide, sulfur dioxide, particulate matter (PM) and particulate matter (PM_{10}). For each of these pollutants, the applicant will have to perform a best available control technology (BACT) demonstration and an ambient air quality analysis. Each of these components of the PSD review process have been discussed in detail in the following sections.

BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Pursuant to Regulation 401 KAR 51:017, Section 9(1) and (2), a major modification subject to a PSD review shall meet the following requirements:

(a) The proposed modification shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.

(b) The proposed modification shall meet each applicable emissions limitation under Title 401, KAR 50 to 65, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

The proposed modification will be a major modification resulting in emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, particulate, particulate-10, and volatile organic compounds (VOC) that exceed the corresponding PSD net significant emission amounts. Therefore, each of these pollutants shall be subject to a BACT review.

Louisville Gas & Electric has presented, in the permit application, a study of the best available control technology for each pollutant and each emissions unit at the proposed source. The Division has reviewed the proposed control technology in conjunction with information available in the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and by U.S. EPA Region IV. A summary of the control technology determined to be the best available control technology for each pollutant and each emissions unit is presented on the following pages:

Simple Cycle Gas Combustion Turbines BACT

Pollutant	Control	Emission Rate

NO_X	Dry Low-NO_X Burners	9 ppmvd[1,2]
CO	Good Combustion	9 ppmvd[1,2]
PM_{10}	Good Combustion/Clean Fuels	19 lb/hr[1]
SO_2	Good Combustion/Clean Fuels	2.0 grains/ 100 SCF - 5.0 lb/hour[1]
VOC	Good Combustion/Clean Fuels	3.2 lb/hour[1]

[1]Based on worst case emissions (at -10°F and 100% load).
[2]Concentration at 15% O_2.

The permittee submitted a top-down Best Available Control Technology (BACT) analysis following the U.S. EPA guidance, "New Source Review Workshop Manual" (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

1. Identify all control technologies,
2. Eliminate technically infeasible options,
3. Rank remaining control technologies by control effectiveness,
4. Evaluate most effective controls considering economic, environmental, and energy impacts, document results, and
5. Select BACT.

<u>A. BACT for Simple Cycle Natural Gas-Fired Combustion Turbines.</u>

This project is being proposed as a simple cycle electrical peaking facility. A simple cycle peaking project is fundamentally different from "combined cycle" baseload power supply systems that represent the majority of listings in the EPA RACT/BACT/LAER Clearinghouse.

Basically, once base load power demands are met, a need still exists to supply additional power at certain times when base load requirements are exceeded by a short term peak power demand. This simple cycle electrical peaking facility configuration meets this short term power supply need. These simple cycle gas-fired combustion turbines must therefore be able to come on-line and supply this power quickly which involves a rapid, quick start-up period. Thermal stress from this rapid start-up process subjects certain materials, such as metals and ceramics, to differential thermal expansion and will cause stress that with cycling may result in failure of equipment if enough time is not taken to bring the temperature up gradually. On a given day, the demand for peak power may be abrupt, requiring quick startup.

This rapid start-up sequence for a peaking plant results in difficulties with applying various control technologies to this project. A distinction must be made between previous BACT decisions for combined cycle units and simple cycle units due to the differing nature of operation and lower exhaust temperatures associated with combined cycle applications. A detailed discussion of the BACT determination submitted by Louisville Gas & Electric is located in Section 5 of the permit application.

Following is a summary of the Control Methods examined and final controls approved as BACT.

<u>NOx</u>

Nitrogen oxides are primarily formed in combustion processes in two ways: (1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal nitrogen oxides), and (2) the oxidation of nitrogen contained in the fuel (fuel nitrogen oxides). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (EPA 1996); therefore, nitrogen oxides emissions from combustion turbines originate as thermal nitrogen oxides. The rate of formation of thermal nitrogen oxides is a function of residence time and free oxygen, and is exponential with peak flame temperature.

Louisville Gas & Electric proposes to implement nitrogen oxides BACT, while firing natural gas, through the use of dry low-NOx burners. GE has, over the years, produced engines that are more efficient and at the same time are capable of achieving lower nitrogen oxide (NOx) emissions. These units are therefore built with dry low-NOx burners which achieve a maximum emission rate of 9 parts per million on a dry volume basis (ppmvd).

Other control technologies were evaluated and more detailed determinations are located on pages 5-1 through 5-13 of the permit application. SCR was eliminated as a control alternative due to economic impact. Catalytic combustion is currently not available for the size and operating parameters necessary for the proposed project and therefore eliminated as a possible NOx control alternative for BACT. Based on the data available and alternate control methods the division agrees that the use of ultra low NOx burners represent BACT for the proposed simple cycle turbine project. The division agrees with the proposed NOx limits of 9 ppm, which are lower than many similar installations.

<u>CO</u>

Carbon monoxide is formed as a result of incomplete combustion of fuel. For carbon monoxide control, the permittee evaluated the following available control technologies: high temperature catalytic oxidation and the front-end technique of good combustion control. The most stringent CO control level available for simple cycle gas turbines would be achieved with the use of a high temperature (zeolite based) oxidation catalyst system, which can remove approximately 80 percent of CO in the flue gas (Booth, 1998, Section 5.4.2.1).

The Division has reviewed the EPA BACT/RACT/LAER Clearinghouse for combustion turbines. Only five cases since early 1990 are documented in the clearinghouse to have specified catalytic oxidation as BACT. The overwhelming majority of determinations specify good combustion practices/good combustion control, proper operation/proper design, and in some cases, no controls.

There are environmental impacts associated with the use of a catalytic oxidation system on a simple-cycle turbine due to the oxidation of SO_2 to SO_3. The SO_3 can react with water or ambient ammonia in the exhaust and form sulfuric acid or ammonia sulfates. There is also generation of hazardous waste from the spent catalyst.

The economic analyses provided for the CO oxidation catalyst are shown in Appendix D of the permit application. The Division has reviewed and accepted cost data provided by the applicant. Because the oxidation catalyst system also removes VOCs, the cost calculation included the additional benefit of reduced VOC emissions, and therefore results in a lower cost-per-ton of pollutant removed than if only CO were considered. This information indicates the total capital investment costs, annualized costs, and overall cost effectiveness for CO and VOC emissions calculated by the permittee. The following table summarizes the results of the overall cost effectiveness of CO and VOC removal for each turbine:

Turbine Model	Overall Cost Effectiveness ($/ton)
GE PG7241 (FA)	$21,299

The annualized cost is taken from the application. The tons per year controlled of carbon monoxide is determined from the 113 TPY of CO per unit potential, with 89% control efficiency and 6 TPY of VOC, with 50% control efficiency, by catalytic oxidation. The cost per ton removed is very high because the combustion turbines emit at very low rates without additional controls. Therefore, although the addition of this technology would reduce emissions by 89%, the actual number of tons removed is very small. The addition of this technology has been determined to be not economically feasible, even for combustion turbines with higher baseline emission rates of 25 ppm, compared with 9 ppm for these proposed turbines.

Considering the potential environmental and energy impacts associated with extended startup times and the economic impact of oxidation catalyst technology, the Division agrees with the permittee's elimination of this control technology.

The next most stringent level of control for CO is efficient combustion control. CO emissions will be limited to 9 ppmvd at 15% oxygen. This level of control is documented as available, and it will not cause negative environmental impacts or operational impacts. This type of control is the most common in the BACT/LAER clearinghouse. Therefore, the division agrees that good combustion control as proposed is BACT for CO emissions.

SO_2

Sulfur dioxide is formed exclusively from the oxidation of the sulfur present in the natural gas fuel.

The emission rate is a function of the sulfur content of the fuel since virtually all the sulfur in the fuel is converted to SO_2. Therefore, utilization of low sulfur fuels is the simplest means for limiting SO_2 emissions. Additional control alternatives include add-on controls such as flue gas desulfurization (FGD) systems.

The permittee has agreed to limit SO_2 emissions by firing natural gas. FGD systems are not typically effective for streams with low SO_2 concentrations, such as those that would result from firing the proposed fuels. In addition, FGD typically operate at temperatures in the range of 400 to 500 °F. The exhaust from the proposed turbines will be in the 1000 °F range. This high exhaust temperature would require conditioning before it could be treated by an FGD.

The Division has reviewed the EPA BACT/RACT/LAER clearinghouse and natural gas/low sulfur fuel is the main control technique used for reducing SO_2 emissions. The applicant's review indicates use of low sulfur fuel as the only available SO_2 control method to be selected as BACT in previous determinations for gas turbines.

This indicates that firing of natural gas is the most stringent SO_2 control technique that has been demonstrated to be feasible for simple cycle gas turbine applications. Therefore, the Division agrees with the permittee's BACT determination for SO_2, which is use of low sulfur fuel/natural gas.

PM/PM_{10}

Particulate emissions from natural gas combustion consist of inert contaminants in natural gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, and particulate of carbon and hydrocarbons resulting from incomplete combustion. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions. Natural Gas is recognized as the cleanest fossil fuel available and is therefore widely used in homes in residential neighborhoods.When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that “particulate emissions from stationary gas turbines are minimal.” EPA noted that particulate control devices are not typically installed on gas turbines and that the cost of installing these is prohibitive (U.S. EPA September 1977). Performance standards for particulate control of stationary gas turbines were, thus, not proposed or promulgated.

The Division has reviewed the EPA BACT/RACT/LAER clearinghouse for gas turbines for particulate control BACT determinations. The Division has found the specification of natural gas as fuel to be the main control technique for particulates. Several listings specify BACT as low sulfur fuel, natural gas as fuel, maintaining the turbines in good working order, good combustion practice and operation, clean burning fuels, and no controls.

Therefore, the use of natural gas and good combustion control is concluded to represent BACT for particulate emissions from the simple cycle gas-fired combustion turbines. This amounts to a specification of 19 lbs/hour/turbine particulate emission limitation. Additionally, the division acknowledges that if the NOx and sulfur limits are met that the combustion control is sufficient to adequately control particulate emissions.

Control of Non-Criteria Pollutants

The combustion of natural gas releases trace amounts of a number of non-criteria pollutants. Two of the PSD regulated pollutants (arsenic and beryllium) require BACT analysis as defined by EPA. As a result, the regulations require that for any potential emission above zero a BACT analysis be performed for these pollutants.

For both arsenic and beryllium the best available control technology is fuel substitution and combustion control. Natural gas contains significantly less ash and metal than coal or residual oil and are therefore considered suitable alternative fuels. Therefore, firing natural gas is considered BACT for arsenic and beryllium.

AIR QUALITY IMPACT ANALYSIS

Pursuant to Regulation 401 KAR 51:017, Section 12, an application for a PSD permit shall contain an analysis of ambient air quality impacts in the area that the proposed facility will affect for each pollutant that it will have the potential to emit in significant amounts as defined in Section 22 of the same regulation. The purpose of this analysis shall be to demonstrate that allowable emissions from the proposed source will not cause or contribute to air pollution in violation of:

(1) A national ambient air quality standard in an air quality control region; or
(2) An applicable maximum allowable increase over the baseline concentration in an area.

For pollutants for which no ambient air quality standard has been established, the analysis shall contain continuous air quality monitoring data gathered to determine if emissions of that pollutant will cause or contribute to a violation of the standard or a maximum allowable increase. The proposed facility will have potential emissions in excess of the significant net emission rates for nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide.

A. Modeling Methodology

The application for the proposed source contains an air dispersion modeling analysis for criteria pollutants (nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24.
3. The PSD increments found in Regulation 401 KAR 51:017, Section 23.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All of the applicable air quality criteria are presented in Table 2. Based on the U.S. EPA suggested procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations.

Table 2

Pollutant	**Averaging Period**	SIL (ug/m^3)	**SMC (ug/m^3)**	**PSD Class II Increments** (ug/m^3)	NAAQS (ug/m^3)
NO_x	Annual	1	14	25	100
PM_{10}	Annual	1	NA	17	50
	24-hour	5	10	30	150
SO_2	Annual	1	NA	20	80
	24-hour	5	13	91	365
	3-hour	25	NA	512	1300
CO	8-hour	500	575	NA	10000
	1-hour	2000	NA	NA	40000

The permittee used the Industrial Source Complex Short Term model (ISCST3, Version 98365, EPA, 1998) in the analysis. The ISCST3 model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per EPA guidance, the ISCST3 model was run with the regulatory default option in a sequential hourly mode using five consecutive years of meteorological data. Surface air data used were based on weather observations taken at the National Weather Service (NWS) station at the Louisville, Kentucky airport from 1987 to 1991. Although more recent surface data are available, the most recent upper air data available from Wright-Patterson Air Force Base is 1991. Thus, this more recent surface data could not be used.

B. Modeling results - Class II Area Impacts

The proposed facility will be located in Trimble County, a Class II area. The permittee modeled the impact of the emissions from the proposed facilities on the ambient air quality and the results of the modeled impacts on the Class II area have been presented in the Table 4.

The modeling results show (Table 3) that the maximum impacts from the proposed facility for NO_x, PM_{10}, SO_2, CO are less than the EPA prescribed significant ambient impact levels (SIL). These concentrations are also below the significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24. Since the maximum predicted impacts for each pollutant are found to be below the SILs, then it is assumed that the proposed facility will not cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling is required at this time. The applicant is also exempted from the ambient monitoring data requirements since the impacts are shown to be below the SMC.

Table 3

Pollutant	Averaging Period	SIL (ug/m3)	SMC (ug/m3)	Max Impact of Emission (ug/m3)
NO_2	**Annual**	**1**	**14**	**0.36**
PM_{10}	**Annual**	**1**	**NA**	**0.16**
	24-hour	**5**	**10**	**1.32**
SO_2	**Annual**	**1**	**NA**	**0.03**
	24-hour	**5**	**13**	**0.23**
	3-hour	**25**	**NA**	**0.76**
CO	**8-hour**	**500**	**575**	**3.11**
	1-hour	**2000**	**NA**	**8.06**

C. Modeling Results - Class I Area Impacts

The nearest federally designated Class I area to the project site is Mammoth Cave, Kentucky. The permittee documents that Mammoth Cave is approximately 160 km southwest of the proposed facility. Based on the results of the dispersion analysis of the proposed project's emissions, it is demonstrated by the permittee that the impacts of the Trimble County facility are less than the recommended EPA and National Park Service Class I screening levels (established through the proposed New Source Review Reform regulations). Thus, the permittee demonstrated that a comprehensive cumulative Class I increment and NAAQS analysis is not required.

The PSD regulations also require a demonstration that the proposed source's emissions would not adversely affect a Class I area's air quality related values (AQRV). Since the proposed source will be located a significant distance from the nearest Class I area, the potential emissions are not predicted to impact a Class I area. Therefore, a Class I AQRV analysis was not required of the permittee.

ADDITIONAL IMPACTS ANALYSIS

A. Growth Analysis

The following information is documented for the proposed facility:

The Louisville Gas & Electric Trimble County project will employ approximately 150 personnel during the construction phase. The existing coal unit currently employs approximately 120 people, and there will be few, if any, additional personnel required to operate the combustion turbines. There should be no substantial increase in community growth, or need for additional infrastructure. The proposed project is also not expected to result in an increase in secondary emissions associated with non-project related activities. Thus, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility itself.

B. Soils and Vegetation Impacts Analysis

The project lies in an area of mainly agricultural use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. The criteria for evaluating impacts on soils and vegetation is taken from EPA's A Screening Procedure for the Impacts of the Air Pollution Sources on Plants, Soils, and Animals (EPA 1980). Because the combustion turbines will be burning extremely low-sulfur natural gas, SO_2 concentrations will be well below sensitive levels that could affect vegetation and soil. (This comparison includes ambient background levels.) The minimum impact level numbers in micrograms per cubic meters are not exceeded by the maximum impact concentration of the Lousville Gas & Electric Trimble County project for the pollutants sulfur dioxide, nitrogen dioxide, carbon monoxide or lead. Therefore, it is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

C. Visibility Impairment Analysis

On the basis of the insignificant modeling results presented in the application, it is also concluded that the facility will have no adverse impact on local visibility, since the significant impact levels are lower than the secondary NAAQS.

Additionally, the permittee has demonstrated that the nearest Class I area is beyond source influence. Therefore, no further analysis was done for visibility impairment.

CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed source should meet all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63 will also be met,

2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels.
   No impact is expected on any Class I area.

3. Impacts on soil, vegetation, and visibility have been predicted to be minimal. A draft permit containing conditions which may ensure compliance with all the applicable requirements listed above has been prepared by the Division. The Division recommends the issuance of the permit following the public notice period, and after the resolution of any adverse comments received by the Division. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Trimble County Clerk's office.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110 Florence, Ky, 41042

CREDIBLE EVIDENCE:

This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has not incorporated these provisions in its air quality regulations.